Locating the End of Tubing for Efficient Production of Gas

Final Report

July 1, 2003

to

December 31, 2004

by

Richard L. Christiansen
John R. Fanchi

January 2005

Penn State Sub-Contract No. 2550-CSM-DOE-1025
DOE Award Number DE-FC26-00NT41025

Petroleum Engineering Department
Colorado School of Mines
Golden, CO 80401-1887
U.S.A

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Abstract

When initially completed, many natural gas wells are capable of lifting water and hydrocarbon liquids to the surface. But, with depletion of the reservoir pressure, there comes a time when liquids can no longer be lifted to the surface and they begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. A key factor for lifting liquids is the location of the end of the tubing in the casing relative to the various gas-bearing formations that have been completed. There is little agreement in the engineering community on the appropriate location for the EOT, or end of tubing.

The objective of this project was to develop technology and guidelines for properly locating the EOT for effective production of gas. Listed below are the two proposed tasks for this stage of the project:

Task 1: Directions for Model Development. Search the literature to assess available commercial software for solving the EOT problem. Begin conceptual development for numerical code specific to the problem.

Task 2: Flow-Loop Testing. Test various locations for the end of tubing in the flow-loop apparatus. Test variations of tubing design, including means for controlled inlet of gas at entry points above the tubing end.

Accomplishments for each of these tasks are summarized below.

Task 1: Directions for Model Development. The EOT problem and associated physical phenomena are described in terms of flow in pipes, and liquid loading. The state-of-the-art of relevant simulation technology in the industry is then assessed, and recommendations on how to model gas well production, deliquification, and associated EOT effects are presented.

Two options for developing a gas well model capable of modeling EOT effects are considered. The first option is to develop a fully coupled wellbore-reservoir model. The second option is to couple a wellbore model to a publicly available simulator. The first option is more accurate and is being pursued commercially, while the second option provides a public domain simulation system.

Task 2: Flow-Loop Testing. Flow-loop tests were performed to study the liquid-lifting rate at the junction of the tubing and casing. In these tests, the distance between the end of the tubing and the bottom of the casing was varied between1 and 5 feet. Liquid was charged to the bottom of the casing and gas flow rate was varied from about 50% to 120% of the critical flow rate for the tubing. In these tests, most of the liquid resided in a churning zone in the bottom 1 foot of the casing. The liquid production rate was measured for each gas flow rate. The liquid production rate was found to fall rapidly toward zero as the distance between the end of tubing and the bottom of the casing increased. It also fell rapidly with decreasing gas flow rate.

These end-of-tubing tests demonstrate that the tubing-casing junction is a bottleneck for liquid production from gas wells. To alleviate the bottleneck, it is apparent that a means for preventing liquid fall-back in the casing is needed. Three different devices were tested for boosting liquid production. The most successful of these was an assembly of rigid circular baffles. The baffles (cut from sheet metal) were mounted on a 3-foot-long slender rod. The space between baffles was 6 inches. The assembly was placed in the bottom of the casing below the end of the tubing. With the baffle assembly in place, the liquid production rate increased by a factor of 10 over a comparable test without the baffles.

Table of Contents

Introduction

The objective of this project is to develop technology and guidelines for properly locating the end-of-tubing (EOT) for effective production of gas. Removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for low permeability gas reservoirs. A key factor is the location of the EOT in the casing relative to the various gas-bearing formations that have been completed. Figure 1 illustrates the system of interest. If not removed, liquids in the casing can decrease gas production rate. There is little agreement in the engineering community on the appropriate location for the EOT.

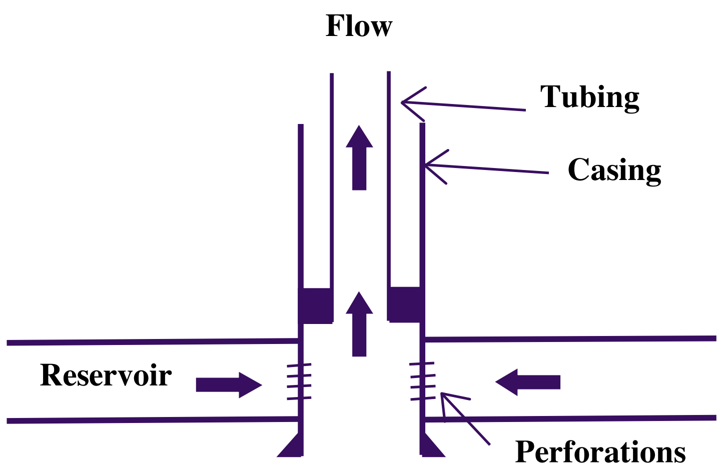

Figure 1. Illustration of End-of-tubing System

The purpose of this report is to present our assessment of the state-of-the-art of simulation methods that can be used to model EOT effects in gas wells, and to present results of flow-loop tests of liquid transport at the tubing-casing junction – the EOT.

In the following section, the approaches used for the two tasks this project are summarized. Then, the results of the two tasks are presented, followed by conclusions and recommendations for future work.

Description of Approaches

Task I: Directions for Model Development.

The state-of-the-art of simulator technology for studying end-of-tubing (EOT) effects in gas wells was determined using a conventional literature search and an informal survey of software vendors. The literature search provides information about studies that have been documented in the open literature. Several software development firms are interested in EOT effects, and a survey of software vendors provides some information about work that is being considered or underway at the time this report was written.

Task II: Flow-Loop Testing

The layout of the flow loop is shown in Figure 2. In brief, gas from the blower mixes with recycle liquid at the bottom of the loop, then the combined stream travels up inside the vertical test section, from which it is re-circulated to the gas-liquid separator. At the gas-liquid separator, the gas exits up to the blower, and the liquid exits down to the recycle pump. The vertical test section and portions of the recirculation lines are made of transparent PVC pipe to allow visual assessment of flow. The flow loop operates near ambient pressure and temperature.

For the end-of-tubing (EOT) tests, the vertical test section consisted of a 2-inch pipe mounted concentrically inside either a 4-inch or a 6-inch pipe as shown in Figure 2. The inner pipe ("tubing") was joined to the larger pipe ("casing") at the top with a rubber sleeve. This configuration was intended to represent the end of the tubing inside the casing of a gas well.

In the EOT tests, 1000 ml of water was charged to the bottom of the test section, gas was circulated at a set of flow rates, and the rate of water production to the separator was measured. The vertical position of the tubing was varied from about 2 feet to 6 feet above the lower end of the casing as noted in Figure 2.

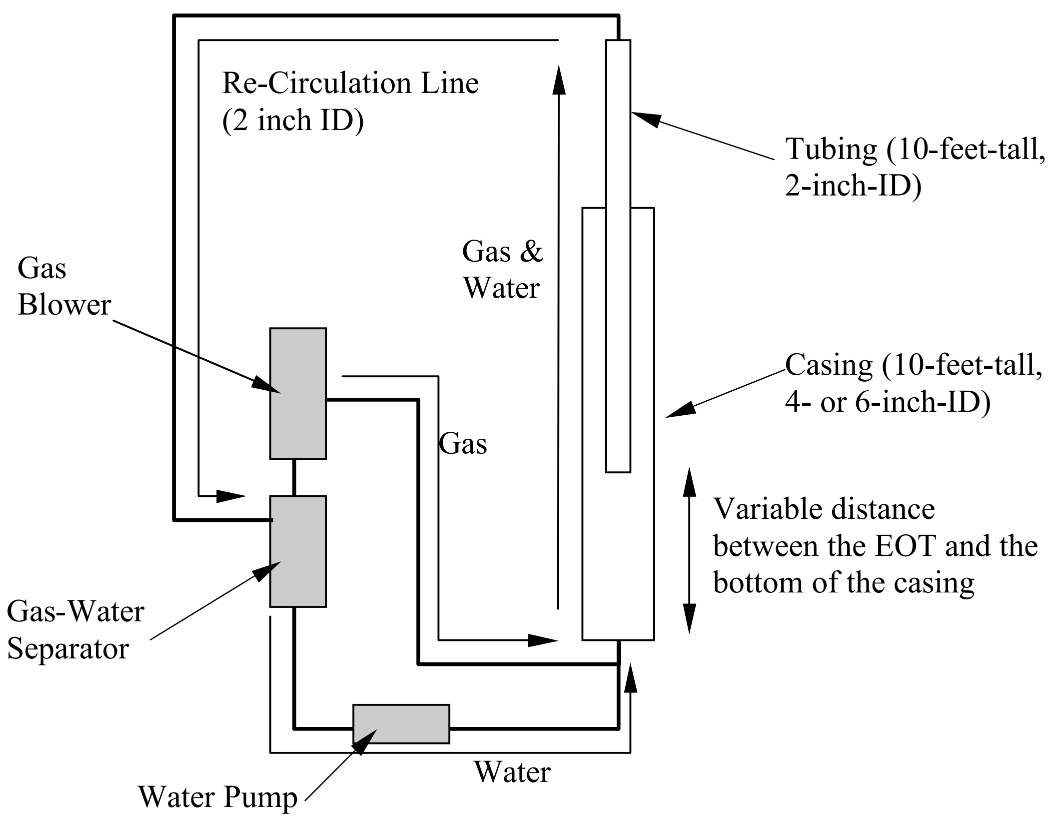

Figure 2. Schematic of Flow Loop.

After completing the EOT tests, a device was developed for increasing transport of water from the casing to the tubing. The device consists of circular sheets (all the same diameter) mounted on a slender rod (3 feet long) as shown in Figure 3. For the first tests of this device, the circles were cut from transparency film. For later tests, the circles were cut from sheet metal. The circles were spaced uniformly on the rod, 6 inches apart. The diameter of the circles was varied from 2 to 3.5 inches.

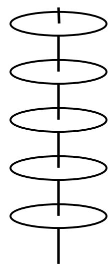

Figure 3. Baffle assembly for lifting liquid in casing.

After testing the above-described baffle assembly, a new implementation of "tubing collar inserts" was tested. We first tested tubing collar inserts 8 years ago (Yamamoto and Christiansen, 1999; Putra and Christiansen, 2001). Tubing collar inserts, as we defined them, provide a slight decrease in the inside diameter of the tubing as shown in Figure 4. We called them tubing collar inserts because we anticipated placing them in the tubing collars. Typically, the inside diameter of the insert is 0.13 to 0.50 inches less than the diameter of the tubing. Surprisingly, even a small diameter upset was found sufficient to prevent fallback of liquid on the walls. In the present tests, the insert was made by cutting a 0.13-inch-thick slice of a 2-inch PVC pipe, and then cutting a section from the slice as in Figure 5. This "split-ring" insert could be slipped inside the 2-inch tubing of the vertical test section by pinching it together. The split-ring insert could be placed easily at any position in the tubing.

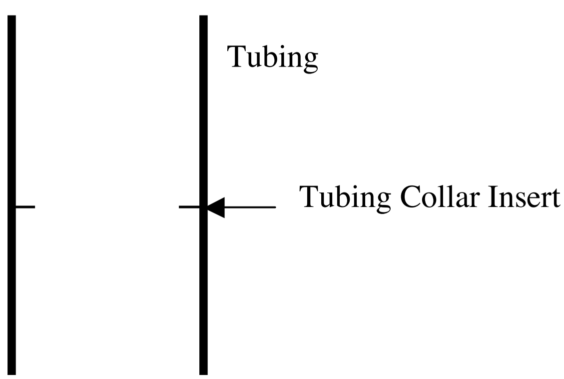

Figure 4. Tubing collar inserts

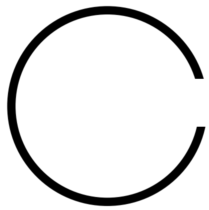

Figure 5. Split-ring insert, a new implementation of tubing-collar insert.

In addition to the above tests, a vortex inducing device was tested in the EOT flow loop. This device was made by cutting an ellipse with a rectangular tab from sheet metal with two cuts on the long axis as shown in Figure 6. Then, the two halves of the ellipse were twisted relative to each other to form an "X" if viewed from the side, with the tabs bent as shown on the right of Figure 6. This device was installed in a coupling that was placed at the bottom end of the tubing of the vertical test section. The tabs in the coupling gap prevented movement. This device proved to be a very simple approach for generating vortex flow.

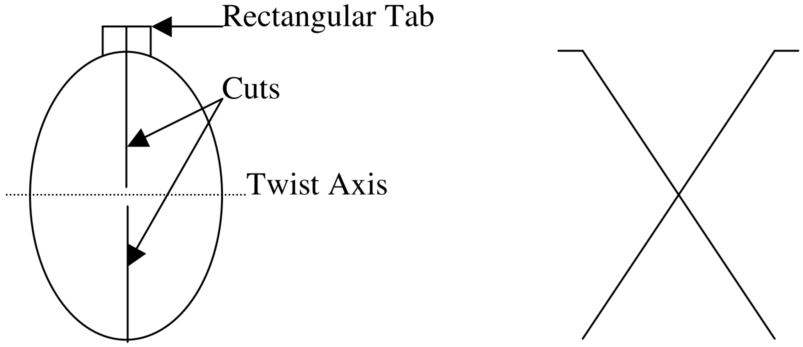

Figure 6. Vortex device. Left: Plan for cutting flat sheet. Right: Side view after twisting and bending the tabs.

Results and Discussion

Task I: Directions for Model Development

An appreciation of the state-of-the-art of simulation methods presumes a familiarity with the phenomenon being modeled. We begin with a description of the physical phenomenon, and then discuss simulation technology. The physical phenomenon of interest here is described in terms of two related phenomena: flow in pipes, and liquid loading. We then present a review of the state-of-the-art of relevant simulation technology that exists in the industry. We conclude with recommendations on how to model gas well production, deliquification, and associated EOT effects.

1. Fluid Flow in Pipes

The end-of-tubing (EOT) problem depends, in part, on fluid flow in pipes. We present a brief summary of factors that affect fluid flow in pipes. Approaches for modeling multiphase flow in pipes are reviewed in the next section.

Fluid flow in pipes can range from laminar to turbulent flow. Fluid does not move transverse to the direction of bulk flow in laminar fluid flow. By contrast, the velocity components of fluid flow fluctuate in all directions relative to the direction of bulk flow when fluid flow is turbulent. For a fluid with a given density and dynamic viscosity flowing in a tube of fixed diameter, the flow regime is laminar at low flow velocities and turbulent at high flow velocities. One parameter that is often used to characterize fluid flow is Reynolds number N_{Re}.

Reynolds number expresses the ratio of inertial (or momentum) forces to viscous forces. For fluid flow in a conduit, the Reynolds number is

$$N_{\mathrm{Re}} = \frac{\rho v D}{\mu} \qquad (1)$$

where ρ is fluid density, v is bulk flow velocity, D is tube diameter for flow in a tube, and μ is the dynamic viscosity of the fluid. The choice of units must yield a dimensionless Reynolds number. In SI units, a dimensionless Reynolds number is obtained if fluid density is in kg/m^3, flow velocity is in m/s, tube diameter is in m, and dynamic viscosity is in Pa·s. Note that 1 cp = 1 mPa·s = 10^{-3} Pa·s.

We introduce the factors that influence fluid flow in pipe by considering the relatively simple case of single-phase flow in circular pipes [Beggs, 1991; Brill and Mukherjee, 1999]. We then discuss multiphase flow and end-of-tubing effects.

Single-Phase Flow in Pipes. Laminar flow along the longitudinal axis of a circular pipe is transverse to the cross-sectional area of the pipe. The cross-sectional area A of a circular pipe with internal radius r and internal diameter D is

$$A = \pi r^2 = \pi\left(\frac{D}{2}\right)^2 \qquad (2)$$

The bulk flow velocity v of a single-phase fluid flowing in the circular pipe is related to volumetric flow rate q by

$$v = \frac{q}{A} = \frac{4q}{\pi D^2} \tag{3}$$

Reynolds number for flow in a circular pipe can be written in terms of volumetric flow rate by substituting Equation 3 into 1 to give

$$N_{\mathrm{Re}} = \frac{\rho v D}{\mu} = \frac{4\rho q}{\pi \mu D} \tag{4}$$

where ρ is fluid density and μ is the dynamic viscosity of the fluid. Fluid flow in circular pipes is laminar if $N_{\mathrm{Re}} < 2000$, and is considered turbulent at larger values of the Reynolds number.

The relationship between fluid flow velocity and pressure change along the longitudinal axis of the circular pipe is obtained by performing an energy balance calculation. The geometry of an inclined circular pipe with length L along the longitudinal axis and angle of inclination θ is shown in Figure 7. The single-phase fluid has density ρ and dynamic viscosity μ. It is flowing in a gravity field with acceleration g.

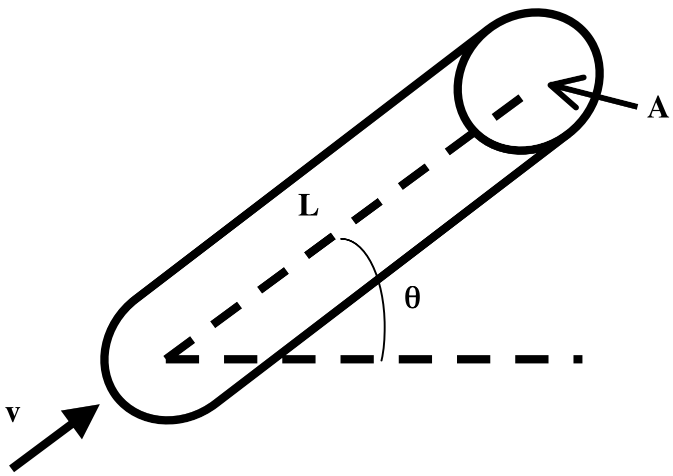

Figure 7. Flow in an inclined circular pipe

We make two simplifying assumptions in our analysis that allow us to minimize external factors and consider only mechanical energy terms. We assume no heat energy is added to the fluid, and we assume no work is done on the system by its surroundings, e.g. no mechanical devices such as pumps or compressors are adding energy to the system. An energy balance with these assumptions yields the pressure gradient equation

$$\frac{dP}{dL} = \left[\frac{dP}{dL}\right]_{PE} + \left[\frac{dP}{dL}\right]_{KE} + \left[\frac{dP}{dL}\right]_{\mathrm{fric}} \tag{5}$$

where P is pressure. We have written the pressure gradient along the longitudinal axis of the pipe as the sum of a potential energy term

$$\left[\frac{dP}{dL}\right]_{PE} = \rho\, g \sin\theta \tag{6}$$

a kinetic energy term

$$\left[\frac{dP}{dL}\right]_{KE} = \tilde{n}\, v \frac{dv}{dL} \tag{7}$$

and a friction term

$$\left[\frac{dP}{dL}\right]_{\text{fric}} = f \frac{\rho v^2}{2D} \tag{8}$$

that depends on a dimensionless friction factor f. If the flow velocity of the fluid does not change appreciably in the pipe, the kinetic energy term can be neglected and the pressure gradient equation reduces to the simpler form

$$\frac{dP}{dL} \approx \rho\, g \sin\theta + f \frac{\rho v^2}{2D} \tag{9}$$

Equation 9 is valid for single-phase, incompressible fluid flow. If we further assume that the right hand side is constant over the length L of the pipe, Equation 9 can be integrated to give the pressure change

$$\Delta P \approx \rho\, g\, L \sin\theta + f \frac{\rho v^2}{2D} L \tag{10}$$

The friction factor f depends on flow regime. For laminar flow with Reynolds number N_{Re} < 2000, the friction factor is inversely proportional to Reynolds number:

$$f = 16/N_{\text{Re}} \tag{11}$$

For turbulent flow, the friction factor depends on Reynolds number and pipe roughness. Pipe roughness can be quantified in terms of relative roughness ζ. Relative roughness is a fraction and is defined relative to the inner diameter of the pipe as

$$\zeta = \ell_p / D < 1 \tag{12}$$

The length ℓ_p is the length of a protrusion from the pipe wall. Typical values of pipe relative roughness ζ range from 0.0001 (smooth) to 0.05 (rough). The length of protrusions inside the pipe may change during the period that the pipe is in service. For example, build-up of scale or pipe wall corrosion can change the relative roughness of the pipe. An estimate of friction factor for turbulent flow is [Beggs, 1991, page 61]

$$\frac{1}{\sqrt{f}} = 1.14 - 2\log\left[\zeta + \frac{21.25}{N_{\mathrm{Re}}^{0.9}}\right] \tag{13}$$

Multiphase Flow in Pipes. The description of single phase fluid flow in pipes presented above is relatively straightforward compared to multiphase flow. In particular, two-phase flow is characterized by the presence of flow regimes or flow patterns [see, for example, Griffith, 1984; Brill, 1987; Brill and Arirachakaran, 1992; Brill and Mukherjee, 1999; Lea, et al., 2003]. The flow pattern represents the physical distribution of gas and liquid phases in the flow conduit. Forces that influence the distribution of phases include buoyancy, turbulence, inertia and surface tension. The relative magnitude of these forces depends on flow rate, the diameter of the conduit, its inclination, and fluid properties of the flowing phases.

Flow regimes for vertical flow are usually represented by four flow regimes [Brill, 1987; and Brill and Mukherjee, 1999]: bubble flow, slug flow, churn flow, and annular flow. Churn flow and annular flow are referred to as slug-annular transition and annular-mist flow respectively by Lea, et al. [2003]. The four flow regimes are illustrated in Figure 8. Bubble flow is the movement of gas bubbles in a continuous liquid phase. Slug flow is the movement of slug units. Each slug unit consists of a gas pocket, a film of liquid surrounding the gas pocket that is moving downward relative to the gas pocket, and a liquid slug with distributed gas bubbles between two gas pockets. Churn flow is the chaotic movement of distorted gas pockets and liquid slugs. Annular flow is the upward movement of a continuous gas phase in the center of the conduit, an annular film of liquid flowing upward between the central gas phase and the wall of the conduit, and dispersed liquid droplets being lifted by the gas phase.

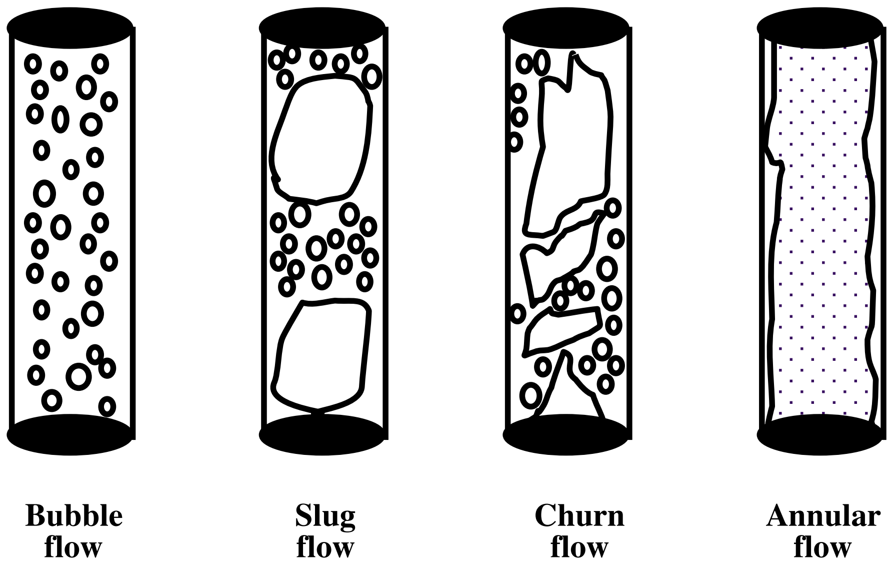

Figure 8. Flow regimes for vertical, two-phase flow (adapted from Brill and Mukherjee [1999, Figure 4.21])

Following Beggs and Brill [1973], Brill and Mukherjee [1999] represent multiphase flow in horizontal conduits using the seven flow regimes shown in Figure 9. These flow regimes are not universally accepted. For example, Brill and Arirachakaran [1992] used a similar set of flow regimes that were organized in terms of stratified flow, intermittent flow, annular flow, and dispersed bubble flow. More recently, Petalas and Aziz [2000] used the following set of flow regimes to represent multiphase flow in pipes: dispersed bubble flow, stratified flow, annular-mist flow, bubble flow, intermittent flow, and froth flow. Froth flow was described as a transition zone between dispersed bubble flow and annular-mist flow, and between annular-mist flow and slug flow.

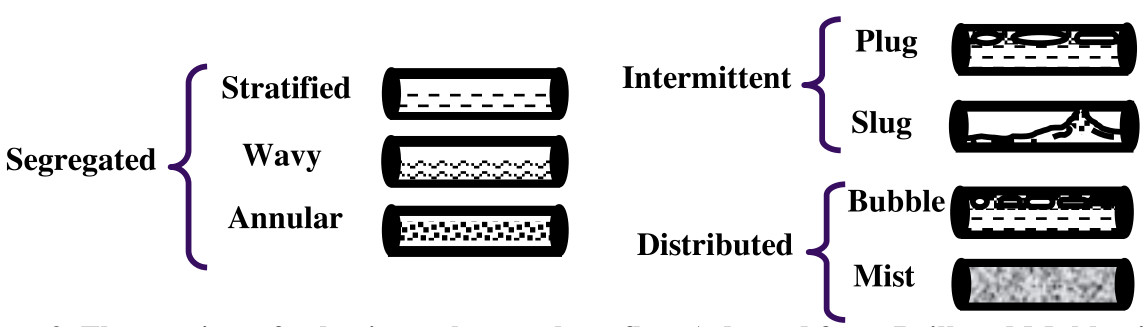

Figure 9. Flow regimes for horizontal, two-phase flow (adapted from Brill and Mukherjee [1999, Figure 4.16])

2. Modeling Multiphase Flow in Pipes

The identification of qualitative flow regimes discussed in Section 1 influences the structure of analytical and numerical models used to quantify multiphase flow in conduits. The flow regimes are used to construct flow regime maps, also called flow pattern maps, which are log-log plots of superficial gas velocity versus superficial liquid velocity. A flow pattern map is illustrated in Figure 10.

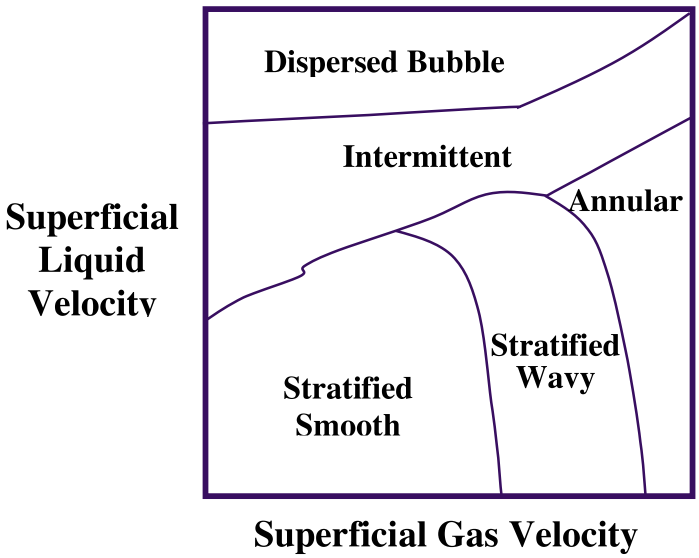

Figure 10. Illustration of a flow pattern map (adapted from Brill and Arirachakaran [1992, Figure 2])

Historically, predictions of multiphase flow in pipes began in the 1950's when investigators used data from laboratory test facilities and, to a lesser extent, field data to prepare empirical flow pattern maps [Brill, 1987; Brill and Arirachakaran, 1992]. Early models of multiphase flow were extrapolations of single phase flow models. Single phase terms in the pressure gradient equation introduced above were replaced with mixture variables. Thus, the terms in the pressure gradient equation for single phase flow given by Equation 5 become

$$\left[\frac{dP}{dL}\right]_{PE} = \rho_m \, g \, sin\theta \tag{14}$$

for potential energy,

$$\left[\frac{dP}{dL}\right]_{KE} = \tilde{n}_m \, v_m \frac{dv_m}{dL} \tag{15}$$

for kinetic energy, and

$$\left[\frac{dP}{dL}\right]_{\text{fric}} = f\,\frac{\rho_m\, v_m{}^2}{2D} \tag{16}$$

for friction. The subscript m attached to variables on the right hand side of Equations 14 through 16 denotes that the associated variable is calculated for a mixture. Early models tended to neglect the kinetic energy term because the degree of turbulence of flow in wells at the time provided enough mixing of multiphase fluids to let the fluids be treated as homogeneous mixtures with gas and liquid phases moving at comparable velocities. Models based on mixture variables are called homogeneous models.

The decline in productivity of wells led to the need for more accurate multiphase flow models to represent phenomena such as gas slippage. In addition to homogeneous models, two other approaches are often used: empirical correlations, and mechanistic models. Empirical correlations depend on fitting experimental data and field data to models that contain groups of physical parameters. The empirical correlations approach can yield useful and accurate results quickly, but does not provide a scientific basis for extrapolation to significantly different systems. By contrast, mechanistic models are based on physical mechanisms that describe all significant flow mechanisms. Modern mechanistic modeling still requires some empiricism to determine poorly known or difficult to measure parameters [Brill and Mukherjee, 1999].

Shi, et al. [2003] observed that mechanistic models are the most accurate models, but are not well suited because they can exhibit discontinuities in pressure drop and holdup at the transition between some flow patterns. One way to solve this problem is to use a drift-flux model. The basic drift-flux model was introduced by Zuber and Findlay [1965]. Drift-flux models are modifications of the homogeneous models described above. From the perspective of reservoir simulation, homogeneous models have the advantages that they are relatively simple, continuous, and differentiable. A significant disadvantage of homogeneous models is that they do not account for slip between fluid phases. Drift-flux models are designed to resolve this deficiency, as well as model counter-current flow. Counter-current flow is the movement of heavy and light phases in opposite directions when there is no net fluid flow in the conduit or the fluid flow is slow. Drift-flux models are used in many reservoir simulators, such as the multi-segment well model in ECLIPSE® black oil and compositional reservoir simulators [Holmes, et al., 1998].

3. Liquid Loading and End-of-Tubing

Sections 1 and 2 discussed flow in pipes as one aspect of the physical phenomenon of interest here. In this section, we discuss the concept of liquid loading in gas wells. We first define liquid loading and identify some deliquification techniques to establish a context for understanding the end-of-tubing (EOT) problem.

Liquid Loading. Few gas wells produce dry gas only. Gas wells often produce varying amounts of water depending on reservoir performance and production operations. For example, high flow rate gas wells are able to carry liquids to the surface. If the gas rate decreases due to reservoir pressure depletion, or the volume of liquid entering the wellbore increases relative to the volume of gas, all of the liquid in the wellbore will not be produced and will begin to accumulate in the base of the well. As another example, gas production from water-drive gas reservoirs can result in water coning and liquid accumulation in the wellbore. The accumulation of liquids in the wellbore is liquid loading.

Liquid loading adversely affects gas well productivity because it results in an increase in flowing bottom-hole pressure and an eventual decrease in gas rate. Turner, et al. [1969] conducted one of the first and most extensive investigations to determine the minimum gas rate that would provide continuous removal of liquids. If enough liquid accumulates in the wellbore, the well may be unable to flow and productivity will be completely lost.

Deliquification Techniques. Removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for maintaining gas well productivity. Several techniques have been developed to deliquify gas wells. Lea, et al. [2003], and Lea and Nickens [2004] discuss several deliquification techniques. These techniques include management of well flow rate, reducing the size of tubing, installing downhole pumps such as electric submersible pumps, installing downhole separators, installing surface pumps, implementing plunger lift, etc. It is often necessary to combine techniques. For example, Aguilera, et al. [2003] used water production wells and gas lift to dewater a naturally fractured reservoir in Argentina and increase gas production.

End-of-Tubing. The location of the EOT in the casing relative to the various gas-bearing formations that have been completed can be used to minimize the affect of liquid loading on gas well productivity. Some researchers have attempted to develop guidelines for setting the EOT. We consider two examples here.

As our first example, we note that Lea, et al. [2003] suggested that the EOT should be set at the top third of the pay interval. They argue that the EOT should not be set below the top third of pay so that liquid accumulating in the wellbore will not cover perforations during well shut-in. On the other hand, they say that the EOT could be set below the top third of the pay zone if the operator knows the perforations are open below the EOT.

It is interesting to contrast the above example with the study by McMullan and Bassiouni [2000]. They used a reservoir simulator to study the impact of the location and length of the perforated interval on ultimate gas and water recovery from a water-drive gas reservoir. The model consisted of a gas zone sitting atop a water zone with properties typical of reservoirs in the Gulf of Mexico. The reservoir simulator included coupling between flow from the reservoir into a well, and a wellbore hydraulics model for flow in the wellbore. Cases were run with the perforated interval in the top half of the gas zone, a perforated interval in the top tenth of the gas zone, and a perforated interval that was completed throughout the gas zone. They found that the length of the perforated interval did not significantly affect ultimate gas recovery, but did affect ultimate water recovery for their gas-water system. These results were sensitive to reservoir and aquifer permeability.

The above examples demonstrate the complexity of the EOT problem and show that it is difficulty to establish general guidelines. Many attempts have been made to model the problem. They are discussed next.

4. State-of-the-Art of Simulator Technology

The state-of-the-art of simulator technology for studying end-of-tubing (EOT) effects in gas wells was determined using a conventional literature search and an informal survey of software vendors. Interest in EOT effects in gas wells has increased as the demand for natural gas has increased. In addition to conventional sources of natural gas, unconventional sources such as tight gas sands and methane from coal seams are being developed. End-of-tubing effects can have a significant, adverse impact on gas well productivity. The literature search provides information about studies that have been documented in the open literature. Several software development firms are interested in EOT effects, and a survey of software vendors provides some information about work that is being considered or underway at the time this report was written. We discuss both the literature search and the vendor survey below. Both surveys rely on wellbore-reservoir coupling, which we now consider.

Wellbore-Reservoir Coupling. We have seen in previous sections that many factors affect multiphase flow in wells. Most of the discussion thus far has focused on wellbore modeling of multiphase flow. These models represent outflow from the wellbore-reservoir system shown in Figure 1. We must also consider inflow into the wellbore.

Wellbore inflow represents fluid flow from the reservoir into the wellbore. Reservoir fluid flow may be modeled using either analytical methods or numerical methods. Analytical methods rely on models of inflow performance relationships (IPR) that were first proposed by Gilbert [1954]. An IPR is the functional relationship between reservoir production rate and bottomhole flowing pressure. Darcy's law is a simple example of an IPR for single phase liquid flow. The gas well backpressure equation is an example of an IPR for single phase gas flow. Vogel [1968] introduced an IPR for the oil rate from a two-phase reservoir. Vogel's IPR depended on absolute open flow potential, which is the flow rate that is obtained when the bottomhole flowing pressure is equal to atmospheric pressure. Fetkovich [1973] proposed a variation of Vogel's model that does a better job of matching field data from producing oil and gas wells. Joshi [1988] proposed an IPR for horizontal wells.

Figure 11 illustrates the relationship between an IPR curve and a Tubing Performance Curve (TPC). It is a plot of fluid flow rate Q_{fluid} versus bottomhole flowing pressure P_{wf}. Reservoir pressure P_{res} is the pressure at $Q_{fluid} = 0$. The intersection of the IPR and TPC curves identifies the flow rate and bottomhole flowing pressure that simultaneously satisfy inflow into the wellbore from the reservoir and outflow from the wellbore.

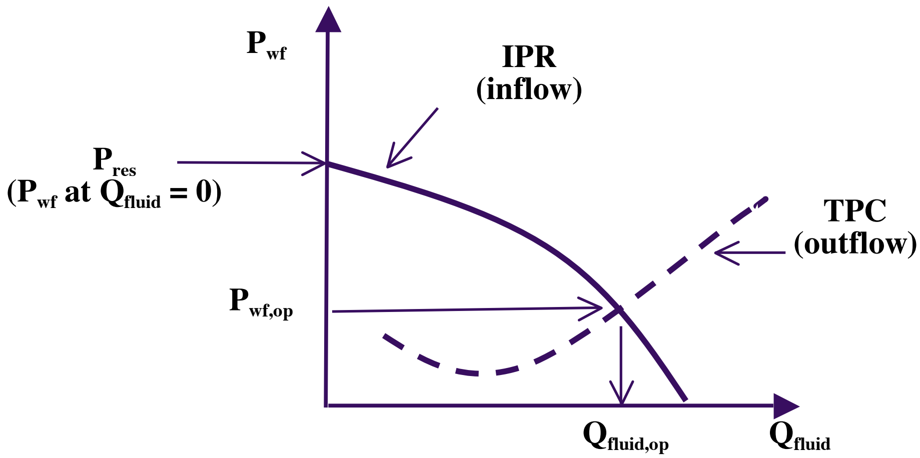

Figure 11. Illustration of an IPR versus TPC Plot

The IPRs described above are examples of analytical representations of fluid flow into a wellbore. Another way to calculate inflow into a wellbore is reservoir simulation. Commercial reservoir simulators typically allow the user to specify tubing curves that relate surface pressure to bottomhole flowing pressure. Williamson and Chappelear [1981] reviewed the traditional representation of wells in reservoir simulators. More recent discussions of well models in reservoir simulators are presented by Ertekin, et al. [2001], Holmes [2001], and Mlacnik and Heinemann [2003].

Tubing curves in reservoir simulators allow the user to specify wellhead pressures and then calculate bottomhole flowing pressures. The tubing curves are typically from empirical correlations, mechanistic models, or drift-flux models. Modelers have found that more sophisticated wellbore models are needed to represent time-dependent (transient) effects in the wellbore. Modern wellbore models are using partial differential equations based on conservation of mass and energy that must be solved numerically in much the same way as flow equations in reservoir simulators. An illustration of a gridding scheme for a coupled wellbore-reservoir system is shown in Figure 12. Gridding schemes for modeling advanced wells are discussed by Mlacnik and Heinemann [2003], and Holmes [2001].

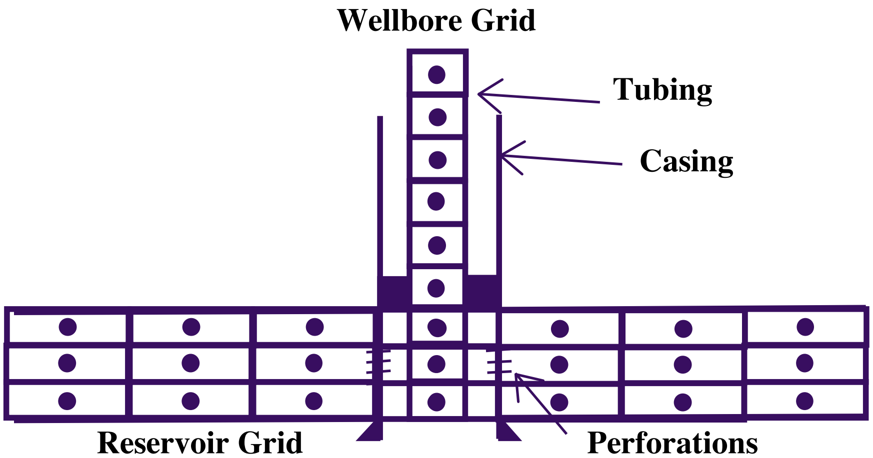

Figure 12. Schematic of a Coupled Wellbore-Reservoir Grid

The degree of coupling of the wellbore model to the reservoir simulator can be used to classify wellbore-reservoir simulators. The coupling may be sequential or implicit. Sequential coupling solves the wellbore model after the reservoir flow calculation is complete. Implicit coupling simultaneously solves the wellbore and reservoir models. Settari and Aziz [1974] used a coupled reservoir-wellbore simulator to study two-phase coning problems. Winterfeld [1989] introduced a formulation that rigorously coupled a reservoir model with a model of multiphase flow in a wellbore to evaluate pressure transient tests. Stone, et al. [1989] developed a coupled reservoir-wellbore simulator that was able to model transient, thermally dependent, three-phase flow (dead oil – water – gas) in the wellbore.

Beginning with Dempsey [1971], some simulators have been designed to couple wellbore and surface facility models to the reservoir model. Dempsey, et al. [1971] developed a simulator that coupled reservoir and surface facilities to study gas-water systems. More recently, Litvak and Darlow [1995] coupled a wellbore model to a compositional simulator that was later used to study the performance of Prudhoe Bay [Litvak, et al., 1997]. Coats, et al., [2004] formulated a black oil – compositional model that was fully coupled to wellbore and surface facility models.

Industry Survey. A select group of companies was identified and queried about their ability to simulate gas well dewatering. The companies were selected based on their experience in reservoir simulator development. The survey pointed out that the removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for producing gas reservoirs. A key factor is the location of the end-of-tubing (EOT) in the casing relative to the various gas-bearing formations that have been completed. If not removed, liquids in the casing will adversely affect gas production. For example, the back pressure of accumulated water on the perforations will decrease production rate. Another adverse effect is the formation of a water block by the back flow of water from the casing through the perforations to the gas-bearing formations.

The survey sought simulators that could model the effects of water accumulation in a gas well. Simulators were expected to couple a reservoir model with a wellbore model. Water should be soluble in the gas phase. The wellbore model should be able to model mass transfer between phases as fluid flows from reservoir conditions to surface conditions. This implies a dependence on both pressure and temperature. Given this background, we asked companies if they had any software that could meet these needs.

Survey responses showed three widely used, practical modeling approaches that could be used to approximate EOT effects. The approaches are summarized in Table 1. Several commercial reservoir simulators are examples of Approach 1. They include such simulators as ECLIPSE by Schlumberger, GEM by Computer Modeling Group, VIP by Landmark Graphics, and SURESim by Seismic Micro-Technology.

Table 1: Practical Modeling Approaches

Approach	Comment
1	Sophisticated reservoir simulator with production tubing curves
2	Sophisticated wellbore simulator with inflow performance relationship
3	Coupled wellbore-reservoir simulator

An example of Approach 2 is the wellbore simulator OLGA [Bendiksen, et al., 1991]. OLGA is a mechanistic, multiphase, transient pipe flow model. It has been used recently to study such effects as gas lift well instability [Hu and Golan, 2003] and transient flow conditions associated with electric submersible pumps in wells with sinusoidal profiles [Noonan, et al., 2003]. It has limited IPR capabilities, however it is possible to sequentially couple OLGA with a reservoir simulator.

A commercial example for Approach 3 is the thermal simulator STARS coupled to the Discretized Well Model (DWM) by Computer Modeling Group. Another example is the proprietary simulator Gensim by EnCana [Edmunds, 2004; Stone, et al., 1989]. The latter simulator uses a drift flux model for transient, multiphase flow in pipes. It was used for modeling such complex phenomena as geothermal effects in thermal production rises [Edmunds and Good, 1996].

5. Directions for Model Development

The transient nature of liquid loading and end-of-tubing (EOT) effects significantly adds to the difficulty of modeling EOT effects. The first two modeling approaches in Table 1 are not as general as Approach 3, which relies on wellbore-reservoir coupling. Two options for developing a gas well model capable of modeling end-of-tubing (EOT) effects are described here.

Option I

The most accurate technique for modeling EOT effects is to use a fully coupled wellbore-reservoir simulator. The wellbore model should be based on a drift flux technique to handle transient wellbore effects, and the reservoir simulator should be fully implicit to represent near wellbore fluid and pressure changes. Efforts to develop fully coupled wellbore-reservoir simulators have been documented in the literature and the technology is being commercialized. Examples of Option I simulators and associated references are discussed in the previous section.

Option II

Option I is the most sophisticated approach to modeling EOT effects. A less sophisticated technique for modeling EOT effects that can provide a more publicly available simulation system in a shorter period of time would be to modify existing public domain software. The United States Department of Energy presently provides the public access to the three-phase, three dimensional simulators BOAST and MASTER [NPTO, 2004].

BOAST and MASTER are implicit pressure-explicit saturation (IMPES) simulators. The formulation in MASTER is mass conserving, while BOAST does not include a mass conserving expansion of the accumulation term [Fanchi, 1986]. On the other hand, the MASTER formulation requires very small time steps (a few days), while longer time steps are possible with BOAST. The lack of a mass conserving expansion in BOAST is a problem primarily when phase transitions occur, such as moving from single phase oil to two-phase gas and oil. One or both of these publicly available simulators could be modified to include a transient wellbore model. To minimize run-time requirements, the transient wellbore model should be based on a drift flux model.

Task II: Flow-Loop Testing

As explained above in **Description of Approaches**, the first flow loop tests explored the effect of vertical position of the end of tubing (EOT) relative to the bottom of the larger pipe ("casing") in the vertical test section. Figure 6 shows results for the tubing in the 4-inch ID casing with the EOT 5 feet above the bottom of the casing. The very important result is that the water-lifting rate below the critical flow rate is extremely small, mostly less than 0.10 bbl/day. The estimated critical flow rate in the figure is for the tubing (not the casing) using the Turner-Hubbard-Dukler (1969) or THD correlation without the 20% increase, as suggested by Coleman *et al*. in 1991. Figure 7 shows results for the EOT 2 feet above the bottom of the casing. In this case, the liquid flow rate is significantly higher, approaching 1 bbl/day for the 4-inch casing at the critical flow rate. For the 6-inch casing, the maximum liquid flow rate is less than 0.4 bbl/day. Composite results for the 4-inch casing are shown in Figure 8. Liquid flow rates as high as 4 bbl/day were observed when the EOT was just 1 foot above the bottom of the casing. In all of these tests, the bulk of the liquid resided in a zone of churning flow regime less than 1 foot tall at the bottom of the casing. At 1 foot above the bottom, the EOT was just above this churning zone. (The height of the churning zone was between 0.5 and 1.0 feet for all flow rates tested.)

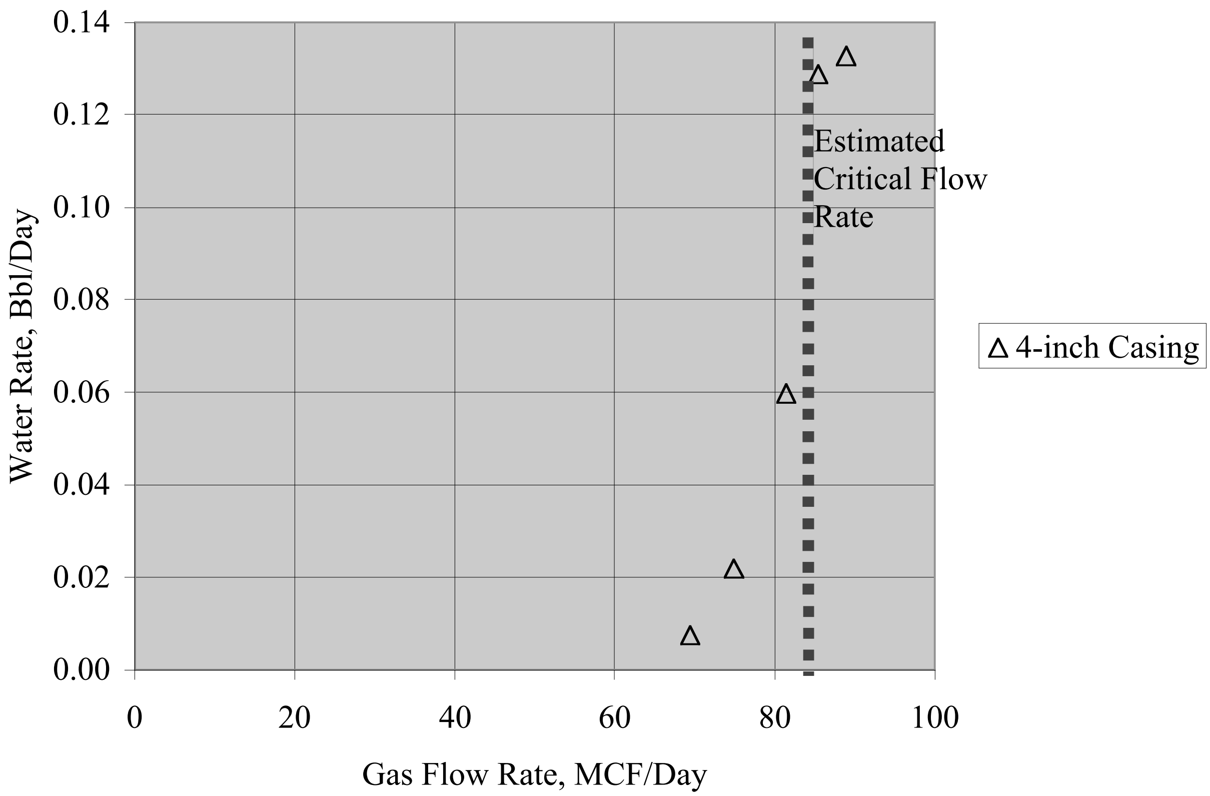

Figure 6. Liquid production for the EOT 5 feet above the bottom of the 4-inch casing.

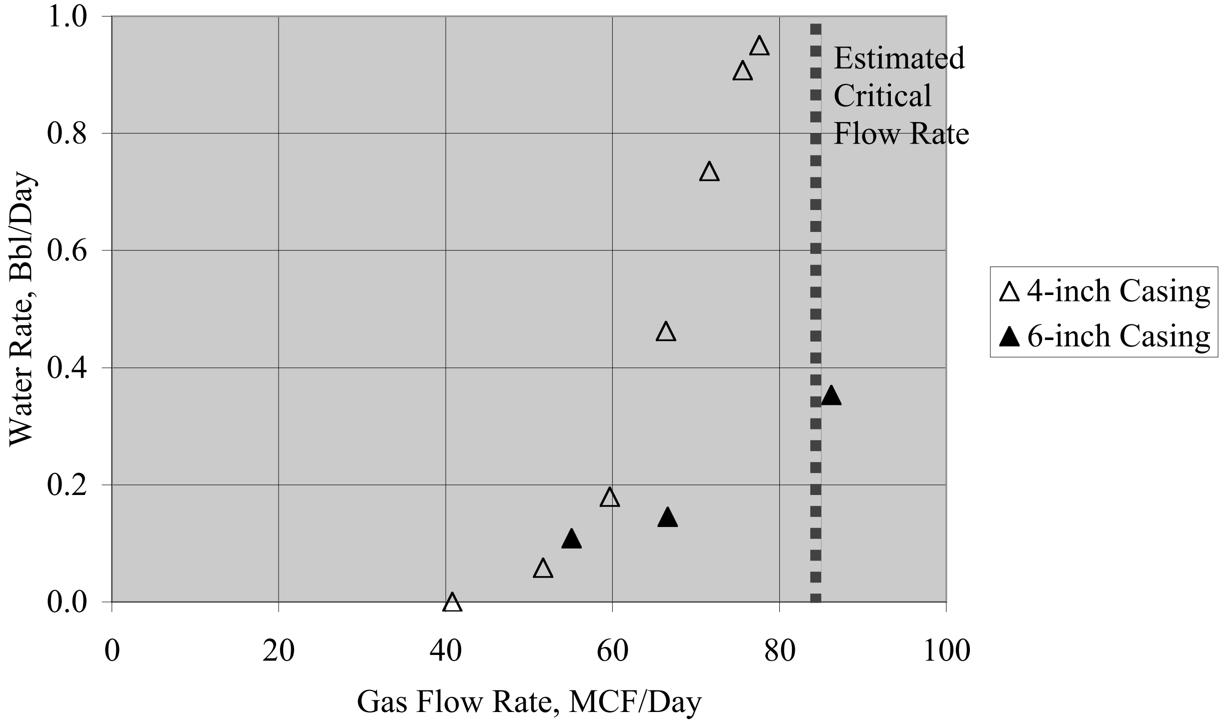

Figure 7. Liquid production for the EOT 2 feet above the bottom of the casing.

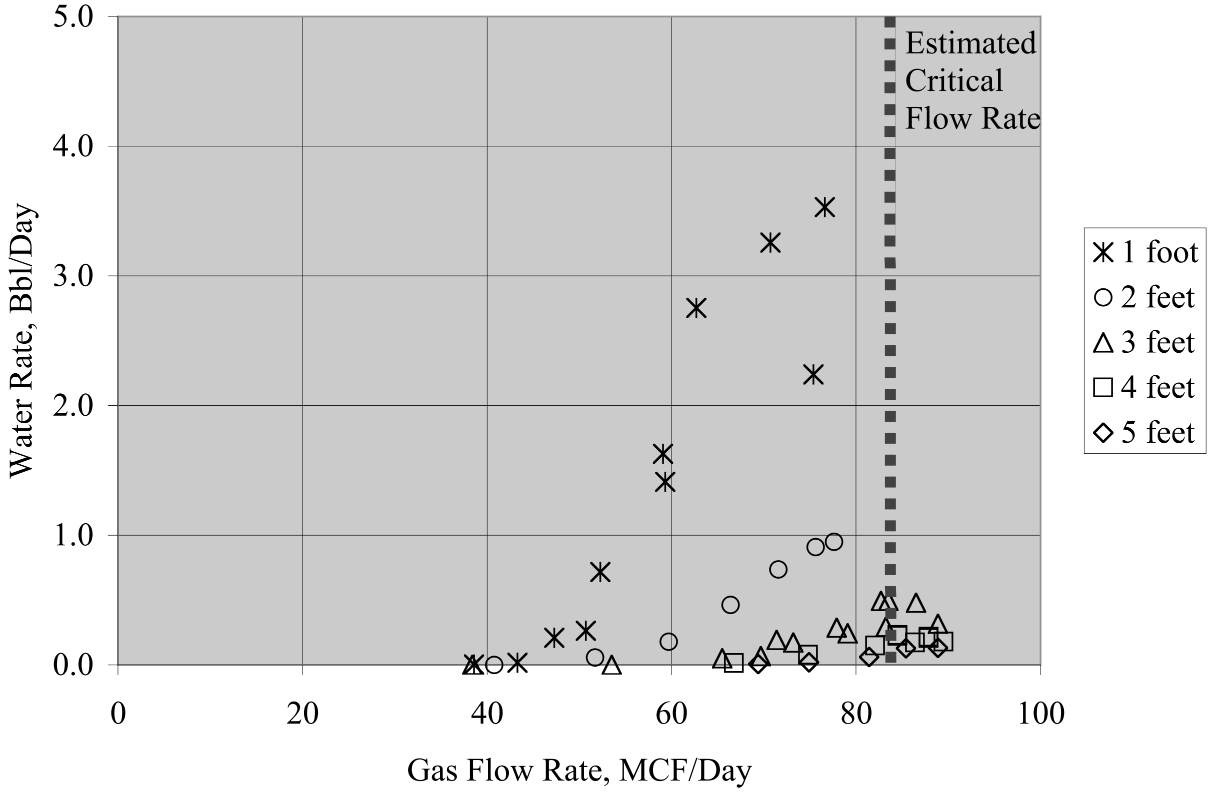

Figure 8. Liquid production for the EOT 1 to 5 feet above the bottom of the 4-inch casing.

The results of Figure 8 show that liquid lifting rate for a tubing-casing system is dominated by liquid transport at the tubing-casing junction. As separation increases between the churning zone in the casing and the EOT, the liquid transport rate rapidly falls toward zero. These results agree with down-hole video observations at the tubing-casing junction that were collected by Centrilift while testing well-bore heating for preventing liquid loading. In that video, the end of the tubing was essentially dry even though a zone of churning liquid was just 10 feet below.

After recognizing the rapid loss of liquid transport rate at the tubing-casing junction, a number of ideas were considered for improving the transport rate. The uniting philosophy of these ideas is prevention of liquid "fall-back." Liquid fall-back is a characteristic feature of churning flow in which most of the liquid that is blown upward in a pipe by the gas stream falls back down the pipe. In previous work (Yamamoto and Christiansen, 1999; Putra and Christiansen, 2001), we found that tubing-collar inserts could prevent liquid fall-back in tubing, so a similar approach was chosen. The ideas rapidly evolved to the baffle assembly of Figure 2. In the first tests of the baffle assembly, the baffles were cut from transparency film, which is quite flexible. While some of the liquid transport results were promising, they were not reproducible. The reason for the lack of reproducibility was thought to be flexibility of the baffles. In some tests, the baffles remained largely flat, while the baffles curled in others. To test this hypothesis, rigid baffles were cut from sheet metal. The results for these tests are summarized in Figure 9.

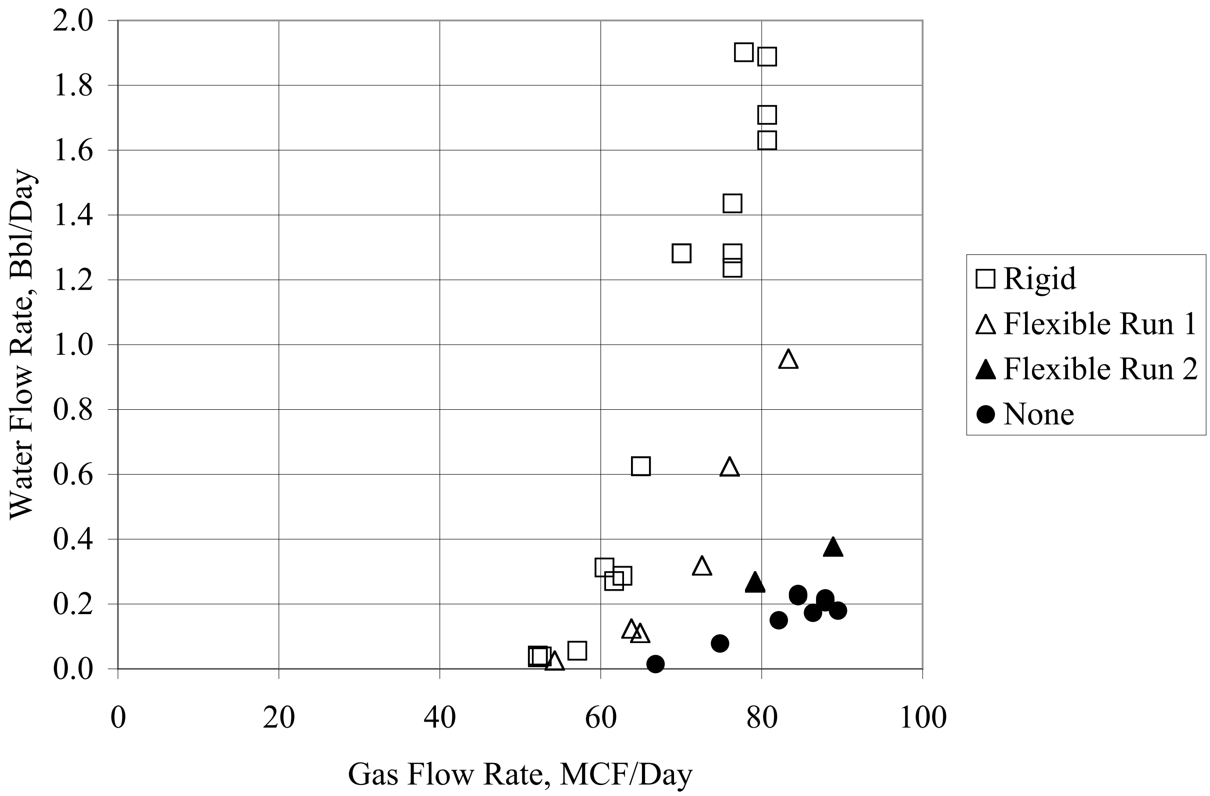

Figure 9. Comparison of performance of 3-inch-diameter rigid and flexible baffle assemblies with EOT 4 feet above the bottom of 4-inch casing.

Figure 9 shows four things. First, liquid-lifting rate for the rigid baffles is 10 times that when no baffles are used. Second, the rigid baffles perform significantly better than the flexible baffles. Third, performance of the flexible baffles is quite variable, as noted before. And fourth, even with the rigid baffle assembly, the liquid lifting rate falls rapidly as gas flow rate declines.

A number of design issues remain for baffle assemblies. The first of these is probably optimum baffle diameter and spacing. Liquid lifting performance for 2-inch-diameter rigid baffles in 4-inch casing was much poorer than the 3-inch baffles and was not measured. In tests with 3.5-inch-diameter baffles, the baffles were levitated by the flow stream – so lifting rates were not measured. The effect of baffle spacing was not explored at all. Another issue that should be explored is the performance of baffles that are rigid near their centers and flexible away from the center. Assemblies of such baffles might be able to slip down the tubing of a well while still providing performance equal to rigid baffle assemblies.

In addition to the baffle assemblies, two other ideas were tested to boost liquid transport at the tubing casing junction: split-ring inserts (Figure 4) and a vortex device (Figure 5). Neither of these ideas proved beneficial. Results for the vortex-inducing device are shown in Figure 10. There, the difference in liquid-lifting rate with and without a vortex-inducing device is insignificant. Although the split-ring inserts did not increase the liquid transport rate at the tubing-casing junction, they may prove useful for lifting in the tubing. Their design may be suitable for placement with a wireline tool.

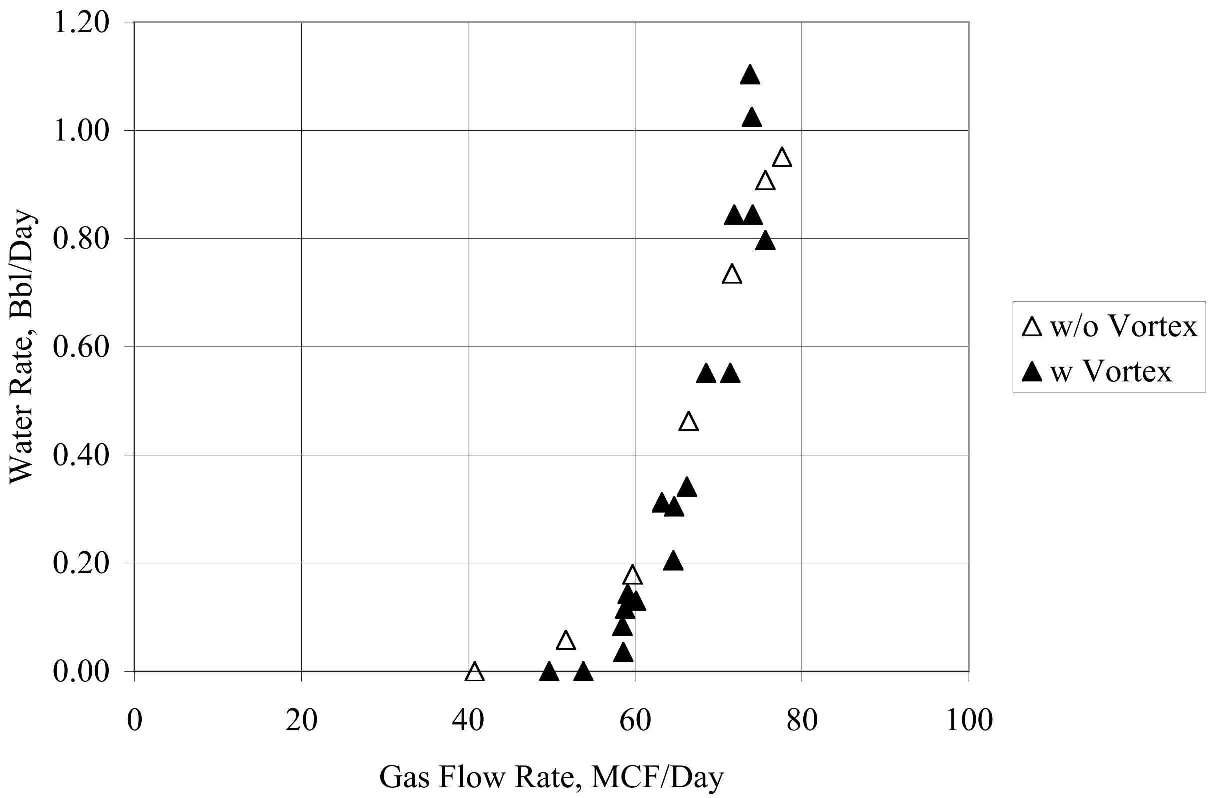

Figure 10. Comparison of liquid lifting rate with and without a vortex-inducing device.

Conclusions

1. An industry survey revealed three widely used, practical modeling approaches that could be used to approximate EOT effects. (See Table 1.)
2. The most accurate technique for modeling EOT effects is to use a fully coupled wellbore-reservoir simulator. The wellbore model should be based on a drift flux technique to handle transient wellbore effects, and the reservoir simulator should be fully implicit to represent near wellbore fluid and pressure changes.
3. Efforts to develop fully coupled wellbore-reservoir simulators have been documented in the literature and the technology is being commercialized.
4. Publicly accessible reservoir models (BOAST and MASTER) could be modified to include a transient wellbore model. The transient wellbore model should be based on a drift flux model.
5. Lifting of liquids is severely impaired by the tubing-casing junction – the end-of-tubing (EOT). Tests in the flow loop showed that the liquid transport rate through the EOT rapidly falls to less than 0.1 bbl/day as the separation between the EOT and the gas-liquid contact in the casing increases to just 5 feet.
6. The rate of liquid transport through the EOT depends on gas velocity and distance between the EOT and the gas-liquid contact in the casing.
7. Several ideas were tested in the flow loop for increasing liquid transport through the EOT. Of these, a system of baffles below the EOT was most successful. Development of baffle systems should be a priority for future SWC funding.
8. A device that induced vortex flow in the tubing above the EOT did not alter the liquid transport rate. Similar results were found for tubing inserts.

References

Aguilera, R., Conti, J.J., and Lagrenade, E., 2003 (December), "Reducing Gas-Production Decline through Dewatering: A Case History from the Naturally Fractured Aguarague Field, Salta, Argentina," *SPE Reservoir Evaluation and Engineering*, 376-386.

Beggs, H.D., 1991, *Production Optimization Using Nodal Analysis*, OGCI Publications, Tulsa, Oklahoma.

Beggs, H.D., and Brill, J.P., 1973 (May), "A Study of Two-Phase Flow in Inclined Pipes," *J. Petroleum Technology*, 607.

Bendiksen, K.H., Malnes, D., Moe, R., and Nuland, S., 1991 (May), "The Dynamic Two-Fluid Model OLGA: Theory and Application," *SPE Production Engineering*, 171 ff.

Brill, J.P., 1987 (January), "Multiphase Flow in Wells," *J. Petroleum Technology*, 15-21.

Brill, J.P., and Arirachakaran, S.J., 1992 (May), "State of the Art in Multiphase Flow," *J. Petroleum Technology*, 538-541.

Brill, J.P., and Mukherjee, H., 1999, *Multiphase Flow in Wells*, SPE Monograph Volume 17, Society of Petroleum Engineers, Richardson, Texas.

Christiansen, R. L.: "New Technologies for Lifting Liquids from Natural Gas Wells," Final Report, DOE Award Number DE-FC26-00NT41025, February 2003.

Christiansen, R. L.: *Two-Phase Flow through Porous Media*, KNQ Engineering, May 2001.

Coleman, S.B., Clay, H.B., McCurdy, D.G., and Lee Norris III, H.: "A New Look at Predicting Gas-Well Load-Up," *J. Pet. Tech.* (March 1991) 329 – 333.

Dempsey, J.R., et al., 1971 (September), "An Efficient Method for Evaluating Gas Field Gathering System Design," *J. Petroleum Technology*, 1067 ff.

Edmunds, N., 2004 (February 3), Private Communication.

Edmunds, N.R., and Good, W.K., 1996 (April), "The Nature and Control of Geyser Phenomena in Thermal Production Risers," *J. Canadian Petroleum Technology*, Volume 35, 41-48.

Ertekin, T., Abou-Kassem, J.H., and King, G.R., 2001, *Basic Applied Reservoir Simulation*, Society of Petroleum Engineers, Richardson, Texas.

Fanchi, J.R., 1986, "BOAST-DRC: Black Oil and Condensate Reservoir Simulation on an IBM-PC," Paper SPE 15297 presented at the Symposium on Petroleum Industry Application of Microcomputers, Silver Creek, Colorado (18-20 June).

Fetkovich, M.J., 1973, "The Isochronal Testing of Oil Wells," Paper SPE 4529 presented at the 1973 SPE Annual Meeting, Las Vegas, Nevada (30 September – 3 October).

Gilbert, W.E., 1954, "Flowing and Gas-Lift Well Performance," *Drilling and Production Practices*, 126 ff.

Griffith, P., 1984 (March), "Multiphase Flow in Pipes," *J. Petroleum Technology*, 361-367.

Holmes, J.A., 2001 (November), "Modeling Advanced Wells in Reservoir Simulation," *J. Petroleum Technology*, 54-66.

Holmes, J.A., Barkve, T., and Lund, O., 1998, "Application of a Multi-segment Well Model to Simulate Flow in Advanced Wells," Paper SPE 50646, presented at the 1998 European Petroleum Conference, The Hague (20-22 October).

Hu, B., and Golan, M., 2003, "Gas-lift Instability Resulted Production Loss and its Remedy by Feedback Control: Dynamical Simulation Results," Paper SPE 84917 presented at the SPE International Improved Oil Recovery Conference, Kuala Lumpur, Malaysia (20-21 October); summarized by Bybee, K., 2004 (May), "Dynamic Simulator predicts Gas Lift Well Instability," *J. Petroleum Technology*, 53-54

Joshi, S.D., 1988 (June), "Augmentation of Well Productivity with Slant and Horizontal Wells," *J. Petroleum Technology*, 729 ff.

Lea, J.F., and Nickens, H.V., 2004 (April), "Solving Gas-Well Liquid-Loading Problems," *J. Petroleum Technology*, 30-31 and 69-74.

Lea, J., Nickens, H.V., and Wells, M., 2003, *Gas Well Deliquification*, Elsevier-Gulf Professional Publishing, Burlington, Massachusetts.

Litvak, M.L., Clark, A.J., Fairchild, J.W., Fossum, M.P., Macdonald, C.J., and Wood, A.R.O., 1997, "Integration of Prudhoe Bay Surface Pipeline Network and Full Field Reservoir Models," Paper SPE 38885 presented at the 1997 SPE Annual Technical Conference and Exhibition, San Antonio, Texas (5-8 October).

Litvak, M.L., and Darlow, B.L., 1995, "Surface Network and Well Tubing-head Pressure Constraints in Compositional Simulation," Paper SPE 29125 presented at the 1995 SPE Symposium on Reservoir Simulation, San Antonio, Texas (12-15 February).

McMullan, J.H., and Bassiouni, Z., 2000, "Optimization of Gas-Well Completion and Production Practices," Paper SPE 58983, presented at the 2000 SPE International Conference and Exhibition, Villahermosa, Mexico (1-3 February).

Mlacnik, M.J., and Heinemann, Z.E., 2003 (August), "Using Well Windows in Full-Field Reservoir Simulation," *SPE Reservoir Evaluation and Engineering*, 275-285.

Noonan, S.G., Kendrick, M.A., Matthews, P.N., Sebastiao, N., Ayling, I., and Wilson, B.L., 2003, "Impact of Transient Flow Conditions on Electric Submersible Pumps in Sinusoidal Well Profiles: A Case Study," Paper SPE 84134 presented at the 2003 SPE Annual Technical Conference and Exhibition, Denver, Colorado (5-8 October).

NPTO (National Petroleum Technology Office), 2004, website www.npto.doe.gov accessed May 17; downloadable software and software documentation available at website.

Petalas, N., and Aziz, K., 2000 (June), "A Mechanistic Model for Multiphase Flow in Pipes," *J. Canadian Petroleum Technology*, 43-55.

Putra, S. A., and Christiansen, R. L.: "Design of Tubing Collar Inserts for Producing Gas Wells Below their Critical Velocity," Paper SPE 71554 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, September 30 - October 3.

Settari, A., and Aziz, K., 1974 (June), "A Computer Model for Two-Phase Coning Simulation," *Society of Petroleum Engineers Journal*, 221-236.

Shi, H., Holmes, J.A., Durlofsky, L.J., Aziz, K., Diaz, L.R., Alkaya, B., and Oddie, G., 2003, "Drift-flux Modeling of Multiphase Flow in Wellbores," Paper SPE 84228, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado (5-8 October).

Stone, T.W., Edmunds, N.R., and Kristoff, B.J., 1989, "A Comprehensive Wellbore-Reservoir Simulator," Paper SPE 18419 presented at the 1989 SPE Symposium on Reservoir Simulation, Houston, Texas (6-8 February).

Turner, R.G., Hubbard, M.G., and Dukler, A.,E., 1969 (November), "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *J. Petroleum Technology*, 1475-1482.

Vogel, J.V., 1968 (January), "Inflow Performance Relationships for Solution-Gas Drive Wells," *J. Petroleum Technology*, 83 ff.

Williamson, A.S., and Chappelear, J.E., 1981 (June), "Representing Wells in Numerical Reservoir Simulation: Part 1 – Theory," *Society of Petroleum Engineers Journal*, 323-338; and "Part 2 – Implementation," *Society of Petroleum Engineers Journal*, 339-344.

Winterfeld, P.H., 1989 (June), "Simulation of Pressure Buildup in a Multiphase Wellbore-Reservoir System," *SPE Formation Evaluation*, 247-252; first presented as Paper SPE 15534, 1986 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana (5-8 October).

Yamamoto, H., and Christiansen, R. L.: "Enhancing Liquid Lift from Low Pressure Gas Reservoirs," Paper SPE 55625 presented at the 1999 SPE Rocky Mountain Regional Meeting, Gillette, Wyoming, May 15-18.

Zuber, N., and Findlay, J.A., 1965, "Average Volumetric Concentration in Two-Phase Flow Systems," *J. Heat Transfer*, *Transactions ASME*, Volume 87, 453-468.